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January 21, 2009

To: Service List

Re: Docket No. 2008-0274; Proceeding to Investigate Implementing a Decoupling Mechanism for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited

In the Order Initiating Investigation, filed on October 24, 2008 ("Order"), the Commission stated that it would be issuing a scoping paper on decoupling. Consistent with the Order, enclosed is a paper titled "'Decoupling' Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission" which was developed by the Commission's consultant, the National Regulatory Research Institute ("NRRI"). Any written comments on the NRRI paper should be provided to the Commission within twenty days of the date of this letter. In addition, the NRRI paper contains appendices, which include requests for information and questions. The Commission directs the parties to respond to the questions in Appendix 2 within thirty days of the date of this letter.

Sincerely,

Carlito P. Caliboso

Carlito P. Caliboso
Chairman

CPC:KKS:laa

Enclosure

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National Regulatory
Research Institute

"Decoupling" Utility Profits from Sales:
Design Issues and Options
for the
Hawaii Public Utilities Commission[1]

David Magnus Boonin

Principal

National Regulatory Research Institute

January 2009

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[1] David Magnus Boonin, Principal of the National Regulatory Research Institute (NRRI), is this document's primary author. The Hawaii PUC has retained NRRI to assist the Commission in several areas relating to the Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and Hawaiian Electric Companies dated October 2008. The purpose of the present document is to provide additional focus to the Hawaii Public Utilities Commission's investigation into decoupling and propose questions and issues that warrant consideration. Any recommendations are for the purpose of further discussion and do not necessarily represent the opinion of the Commission, NRRI, or any individual.

Table of Contents

Decoupling Utility Sales and Earnings:

Design Issues and Options

I. Driving forces that cause the Commission to consider decoupling

A. Traditional utility rate design links a utility's earnings[2] to a utility's sales

A utility, like any business, has fixed costs and variable costs. Fixed costs (including the utility's authorized return on investment) do not vary with output. Variable costs vary with output. Traditional utility rate design has a fixed component (i.e., an amount paid by the consumer regardless of the amount consumed), and a variable component (i.e., an amount that varies with the amount consumed, sometimes called the "volumetric" component). In traditional rate design, the fixed (customer) and variable (volumetric) charges do not track the utility's fixed and variable costs. The utility recovers only part of its fixed costs through the fixed charge; it recovers the remainder of its fixed costs through the volumetric charge. As sales decrease, so does the utility's recovery of its fixed costs and its earnings.

When a utility recovers fixed costs and earnings through volumetric charges, it increases profits by increasing sales. Conversely, as sales decrease, so does the utility's recovery of its fixed costs and its earnings. Depending on the rate design, a slight drop in sales can cause a large decrease in earnings. The example in Table 1 shows a 5% decrease in sales and a 30% decrease in earnings. A 5% increase in sales produces a 30% increase in earnings.

[2] The author has chosen to use "earnings" rather than "profits," although the terms are synonymous. Earnings, herein, means net earnings (revenues, minus all fixed costs including interest, depreciation, and taxes but excluding return on equity and all variable costs such as fuel and purchased power). For simplicity, none of the examples explicitly addresses income taxes, which do not affect the calculation as explained at III.B.

Table 1: Effect on Sales and Earnings[3]			
	Sales of 1000 kWh (base case)	**Sales of 950 kWh (- 5% from base[4])**	**Sales of 1050 kWh (+5% from base[5])**
Revenue @ $0.10/kWh	$100	$95	$105
Fixed Costs	$50	$50	$50
Variable Costs @ $0.04/kWh	$40	$38	$42
Earnings (Revenue-fixed and Variable Costs)	$10	$7 (-30%)	$13 (+30%)

The more a utility recovers its fixed costs from volumetric charges, the more a change in sales will affect earnings (see section I.C.3, below).

This "coupling" of sales and earnings caused by traditional rate design makes utilities naturally resistant to conservation, energy efficiency, demand-side resources (DSR), behind-the-meter distributed generation, and other actions that reduce sales. Decoupling is any mechanism that breaks the link between utility sales and earnings, so that a reduction in sales leaves utility earnings unaffected. Breaking the link between sales and earnings eliminates the financial penalty incurred by utilities through cost-effective programs that reduce sales. Decoupling does not reconcile utility earnings caused by anything other than changes in sales. Changes in costs

[3] Throughout this document, the author uses values in his examples such as revenue of $0.10/kWh or variable costs of $0.04/kWh. These values are not indicative of the revenues or costs experienced in Hawaii and are used for clarity of presentation and ease of calculation.

[4] 30% is calculated by looking at lost earnings of $3 ($10 base minus $7 from the 950kWh case) and comparing the lost earnings to the $10 in earnings in the base case.

[5] 30% is calculated by looking at lost earnings of $3 ($10 base minus $7 from the 950kWh case) and comparing the lost earnings to the $10 in earnings in the base case.

can affect earnings. Regulators deal with cost changes through fuel adjustment clauses, other cost adjustment clauses, cost or rate indexing, and rate cases. Decoupling focuses only on changes in earnings caused by changes in sales.

There are several approaches to mitigate coupling, as discussed at section II. Some of these approaches require that the regulator establish rate riders that charge customers an additional fee to offset changes in earnings caused by changes in sales. This paper refers to the dollars collected through the rate rider to achieve this offset as the *decoupling adjustment.* The decoupling mechanism approved by regulators must convert the decoupling adjustment into decoupling charges paid by customers to offset earnings to the approved amount. Depending on the general decoupling mechanism chosen by the regulator, a decrease in sales will result in a positive decoupling adjustment and charge to offset lost income. An increase in sales will result in a negative decoupling adjustment and charge. Hawaii uses an independent third party administrator to implement utility sponsored energy efficiency programs. The Commission should consider how the use of an independent administrator affects the need for a decoupling mechanism, if the need for decoupling is based on encouraging utilities to promote energy efficiency as a resource.

B. Why is decoupling needed now?

Section 28 of the Agreement among the State of Hawaii, Division of Consumer Advocate of the Department of Commerce and Consumer Affairs and the Hawaiian Electric Companies of October 2008 (the Agreement), entitled "Decoupling from Sales," calls for the Commission to consider decoupling. Section 28 of the Agreement is available at Appendix 1.

The purpose of this paper is to establish an objective foundation for Hawaii's discussions about decoupling. The focus is on decoupling mechanisms that break the existing link between sales and earnings arising from traditional rate design, which recovers a portion of fixed costs through the volumetric charges in two-part tariffs. This paper does not consider creating incentives for energy efficiency, focusing instead on removing the aforementioned disincentive. Further, this paper does not consider the issues raised at section 28 of the Agreement at 1b (recovery of and on investments, which is an incentive or cost recovery issue beyond the scope of decoupling), 1c (which addresses adjusting utility rates for changes in state or federal taxes and can be attended to separately), and 3 (which addresses the continuation of the pension cost tracking mechanism).

Part II below will discuss the four basic methods used to achieve decoupling. **Part III** then will discuss implementation issues, and **Part IV** suggests next steps for this proceeding. Discussed next are five foundational concepts common to all decoupling methods.

C. Decoupling – Foundational concepts common to all decoupling mechanisms

1. The goal is to protect earnings, not revenues, from decline in sales

Although often referred to as "revenue decoupling," the actual goal of decoupling is to protect a utility's earnings, not its revenue, from a decline in sales. If decoupling holds a utility's revenues rather than its earnings constant, the utility will earn more than its authorized earnings when sales decrease, all else being equal. Full revenue-based decoupling adjustments and their related charges allow a utility to collect revenue associated with variable costs that the utility is no longer incurring because cost-causing sales have decreased. Table 2 shows how adjusting revenues rather than earnings creates additional earnings when sales decrease. Under the revenue approach, the utility recovers $0.04/kWh in variable costs for the 50 kWh it is no longer supplying, and earnings are $2 or 20% higher than in the base case. Note that a revenue-based decoupling adjustment for an increase in sales of 50 kWh would produce earnings of $8 or $2 less than the authorized amount. Adjusting earnings keeps a utility neutral about sales. Adjusting revenues that include variable costs creates an incentive for utilities to reduce sales and penalizes utilities for increased sales, regardless of the reason.

Table 2: Decoupling of Revenue or Earnings

	Adjustment Based upon Revenue	**Adjustment Based upon Earnings**
Base Case: Sales of 1000 kWh		
Revenues ($0.10/kWh)	$100	$100
Fixed Costs	$50	$50
Variable Costs ($0.04/kWh)	<u>$40</u>	<u>$40</u>
Earnings	**$10**	**$10**
Actual Case: Sales of 950 kWh		
Revenues ($0.10/kWh)	$95	$95
Fixed Costs	$50	$50
Variable Costs($0.04/kWh)	<u>$38</u>	<u>$38</u>
Earnings	$7	$7
Decoupling Adjustment	$5 (total revenue loss of $$100-$95)	$3 (equals $5 revenue loss less $2 variable cost gain)
New Earnings ($7 in earnings plus adjustment)	**$12** **($2 or 20% higher than authorized)** ($2 = 50 kWh x $0.04 in variable costs)	**$10** **(equal to authorized)**

See section I.C.4 for a discussion on how decoupling revenues rather than earnings effects customers' incentive to conserve. Other than the discussion in this section and the section on how decoupling affects conservation, revenue decoupling is not discussed in this paper.

2. Decoupling adjustments caused by lost sales increase customer average price, but not the average customer's bill or a utility's revenue requirement

Decoupling adjustments associated with reduced sales increase the average price per kWh but do not increase the average customer's bill compared to before the reduction in sales or the utility's allowed revenue requirement. Table 3 shows that the average price is higher in the right-hand column after sales have decreased and a decoupling adjustment is charged ($0.103/kWh compared to the original price of $0.10/kWh), but that the total revenue and the average revenue per customer are lower.

Table 3: Effect of Decoupling on Rates and Revenue Requirement

	Base Sales of 1000 kWh	**Actual Sales of 950 kWh with Decoupling Adjustment**
Revenue Required to Keep Earnings Constant ($50 in fixed costs plus usage x variable cost of $0.04/kWh)	$100	$98
Average Price (Revenue/Sales)	$0.10/kWh	$0.103/kWh
Average Bill (5 customers assumed)	$20.00	$19.60

Decoupling associated with increased sales (e.g., harsher weather than expected when the regulator set sales in a rate case) decreases the price ($/kWh), mitigating the effects of higher than expected sales on a customer's bill. A decoupling adjustment lessens the burden on customers of these unexpected purchases (by $3 in Table 4). Decoupling has sent $3 in earnings over authorized earnings generated by the increased sales to customers in the form of a negative decoupling charge of $0.003/kwh (the difference between $0.10/kWh and $0.097/kWh).

Table 4: Effect of Greater than Expected Sales on Average Price and Customer Bills with and without Decoupling		
	Without Decoupling	**With Decoupling**
Normal Sales	1000 kWh	1000kWh
Actual Sales	1050 kWh	1050 kWh
Base Revenues (Actual Sales x $0.10/kWh)	$105	$105
Decoupling Adjustment	NA	-$3.00 (-$0.06/kwh of fixed costs in variable charge x 50 kWh)[6]
Total Revenues	$105	$102
Total Earnings (Total Revenues -$50 in fixed costs minus$0.04/kWh in variable costs x sales)	$13.00 ($3.00 more than $10.00 authorized)	$10.00 (equal to authorized amount)
Average Price (Revenue/Sales)	**$0.10/kWh**	**$0.097/kWh**
Average Bill (5 customers assumed)	**$21.00**	**$20.40**

3. The larger the share of fixed costs recovered through volumetric charges, the greater the need to decouple earnings from sales

The larger the proportion of a utility's fixed costs recovered through volumetric charges, the greater the effect sales have on earnings and thus the greater the need for decoupling. Table 5 shows two cases that are identical except that one has a tariff with a tail block (the portion of a utility's tariff that covers the change in sales) of $0.10 per kWh and the other a tail block of $0.15/kWh. The higher tail block case has a 55% decrease in earnings compared to a 30% decrease in the other case. This heightened sensitivity to changes in sales increases the

[6] Eliminates fixed cost recovery from sales associated with harsher than normal weather.

importance of earnings decoupling. As discussed further at section II.D below, a straight-fixed variable rate design that recovers all a utility's fixed costs including earnings through fixed (i.e., non-volumetric) charges eliminates the coupling of sales and earnings.

Table 5: Effect of Rate Design		
	Flat Rate Design **All kWh @ $0.10/kWh**	**Inverted Rate Design** **First 500 kWh @ $0.05/kwh** **Over 500 kWh @ $0.15/kWh**
Base Case of 1000 kWh		
Revenue	$100	$100
Authorized Earnings	$10	$10
Actual Case of 950kWh		
Revenue	$95.00	$92.50
Earnings (revenues minus variable costs of $0.04/kWh times sales)	**$7.00 (-30%)**	**$4.50 (-55%)**

4. Decoupling changes customers' incentive to conserve

Decoupling introduces an additional charge to customers when utility sales go down. This additional charge associated with reduced usage reduces customers' savings associated with conservation. Customers sometimes need to make energy savings investments (e.g., insulation, set-back thermostats) to achieve energy savings. Customers sometimes measure the cost effectiveness of these investments by the length of the payback period (investment divided by the annual electricity bill savings). Case 1 in Table 6 shows that when all customers reduce their usage by the same amount, the customer's payback is longer with earnings decoupling than without decoupling. If revenue decoupling is used and all customers conserve the same, there is no financial incentive to conserve as all lost revenues are recaptured by the utility through the decoupling adjustment. This produces an infinite payback for customer financed conservation investments.

All customers do not usually behave in the same way. Case 2 assumes the same change in overall usage as in Case 1, but makes one customer (or group of customers) responsible for all the investments and savings and leaves another customer's (or group of customers') usage unchanged. The effect of the decoupling adjustment in Case 2 is much less than in Case 1. The customer's payback period increases from a pre-decoupling level of 4 years to 5.6 years in Case 2, compared with 10 years in Case 1.

Case 2 also shows that customers who do not conserve pay $1.58 more with earnings decoupling and $2.63 more with revenue decoupling than without decoupling. This increase in the non-conserving customer's bill is an additional incentive for customers to keep pace with the energy efficiency practices of other customers.

Table 6: Decoupling as a Conservation Disincentive and Incentive

Case 1: Everyone Conserves 5% through a $20 Investment	**Without Decoupling**	**With Decoupling of Earnings**	**With Decoupling of Revenues**
Base Revenue	$100	$100	$100
Revenue after Conservation	$95	$95	$95
Decoupling Adjustment	$0	$3	$5
Annual Savings	$5	$2	$0
Payback ($20 investment/annual savings)	**4 years**	**10 years**	**Infinite**
Case 2: 2 Customers with Equal Base Usage. One Conserves 10%. One Conserves 0%.			
Conserver			
Base Revenue	$50	$50	$50
Revenue after Conservation	$45	$45	$45
Decoupling Adjustment	$0	$1.42	$2.37
Annual Savings (Base revenue minus sum of revenue after conservation and decoupling adjustment)	$5	$3.58	$2.63
Payback ($20 investment/annual savings)	**4 years**	**5.6 years**	**7.6 years**
Unchanged Customer			
Base Revenue (no conservation)	$50	$50	$50
Decoupling Adjustment	$0	$1.58	$2.63
Bill Increase (extra incentive to conserve)	**$0**	**$1.58 (+3%)**	**$2.63 (+5%)**

5. On-site generation affects sales and earnings

Behind-the-meter on-site generation affects a utility's sales and earnings identically to energy efficiency improvements implemented by the customer at the same location. Behind-the-meter on-site generation is energy produced at the customer's site, which the customer may use instead of accepting power from the utility. Where on-site generation produces electricity in excess of the customer's needs, the customer puts the excess on the utility's grid and the utility nets the excess electricity from the customer's electric bill. The practice of netting the excess production from the amount of electricity billed by the utility is called net metering. Net metering is a tool used by regulators to encourage the development of certain renewable resources. Net metering and self-use of on-site generation both cause the utility to lose sales, just like the results of customers' energy efficiency efforts. Some decoupling mechanisms recognize these reductions in billable sales in the same way they recognize reductions in sales associated with energy efficiency. If the regulator's objective is to encourage the use of renewable resources, decoupling is necessary to eliminate the disincentive of sales losses associated with renewable resources.

II. Four basic approaches to decoupling

There are four basic approaches to decoupling. Three of theses approaches adjust customers' bills though an additional rate rider for the amount of earnings changed due to changes in sales from a level approved by the regulator. The fourth method is a base rate design that removes all fixed costs from volumetric charges and thereby eliminates any further need for a decoupling adjustment charge.

Utility sales fluctuate for many reasons, including the weather; the economy; the number of customers; price elasticity responses; external energy efficiency measures, such as appliance standards; utility energy efficiency programs; new technology (plasma televisions or plug-in vehicles); demand-side resource initiatives; and behind-the-meter generation. Some of these factors drive sales upward, while others drive sales downward. Some of these factors are within the utility's control while others are not. The regulator must decide which changes in sales to include in a decoupling mechanism. A regulator can design a decoupling mechanism to recover

- sales losses associated with utility-sponsored energy efficiency programs;
- all changes in earnings associated with any change in sales regardless of the reason for the change in sales; or
- changes in earnings based upon average usage per customer (the same as the second approach if the customer population remains constant).

Each approach requires that the regulator understand which utility costs are fixed and which are variable. Each method requires the regulator to make decisions about billing, base sales, the effect on risk and rate of return, and the need for customer education related to the decoupling charge (see section III, below). The following sections describe each of the four basic decoupling mechanisms. The four mechanisms are compared at Section II.E.

A. Lost earnings tracker

Lost earnings trackers address the sales and earnings losses associated with specific programs. The energy efficiency programs included for earnings adjustments are usually limited to programs implemented directly by the utility's personnel and utility-funded programs implemented by third party service providers. The lost earnings tracking mechanism aims to make a utility's earnings whole for losses in sales associated with the utility's own actions. The tracker adjusts only for sales losses and not sales gains.

The tracker assigns sales losses to each included energy efficiency program based upon engineering analyses and then multiplies the lost sales by lost fixed costs per kWh. If, for example, the program gives away compact fluorescent bulbs, the tracker calculates a decoupling adjustment equal to a certain number of saved kWh per bulb per period and multiplies the lost kWh by the fixed costs that would have been recovered through those sales. It is difficult to estimate sales losses driven by new rate structures or customer education programs, so these utility programs often are excluded from the calculation of lost sales and earnings by the tracker.

Lost earnings trackers usually do not recover lost earnings associated with distributed generation, although separate metering of distributed generation can track sales losses. Sales changes for reasons other than specific energy efficiency programs, such as the weather, changes in the business cycle, or building or appliance codes, are not included in the lost earnings tracker.

The tracking mechanism requires not only that the regulator set the sales losses for each utility action, but also that the utility continuously monitor and evaluate their reasonableness. Administratively, this method requires program monitoring, auditing, hearings, and reconciliation[7] of actual collections to allowed collections of lost earnings.

The tracker does remove the lost earnings disincentive that a utility has for encouraging the specific programs included in the tracking method and therefore allows the utility to view certain demand-side resources more as it views supply-side resources. Other energy efficiency resources remain strapped by the earnings loss disincentive. The remaining disincentive lingers as an impediment to the development of excluded cost-effective sales-reducing energy resource strategies.

B. Total sales adjustment

The total sales approach adjusts a utility's earnings for any change, up or down, in sales from the baseline usually set in the utility's rate case as the normal or expected sales upon which revenues are determined. This is the decoupling method proposed by the parties to the Agreement. The total sales approach adjusts customers' bills to recover or refund the change in earnings caused by the change in sales, regardless of the reason for the change. Changes in the weather or the economy that affect sales are treated the same as utility-sponsored programs. The decoupling adjustment is calculated by comparing actual sales to baseline sales and then multiplying the difference by the fixed costs that should have been recovered per unit in the case of a sales decrease. The total sales adjustment (unlike the tracker discussed above at II.A) is symmetrical in that it adjusts for sales losses and sales gains.

Total sales decoupling mechanisms adjust for earnings changes associated with sales changes and do not adjust earnings for changes in costs (e.g., fuel adjustment clauses or inflation adjustments). Total sales adjustments make a utility indifferent (based upon achieved earnings) to any change in sales as sales and earnings are decoupled to the extent of the accuracy of the underlying assumptions and calculations about earnings and sales changes (accuracy of decoupling calculations is discussed further at section III.A). All demand-side resources have

[7] Decoupling mechanisms usually operate by first setting a dollar amount and then charging customers based upon expected sales (i.e., the decoupling charge equals the decoupling adjustment divided by expected sales). Under- or over-collections occur whenever an expected sales used to establish the charge differ from actual sales used when the charge is collected from customers.

had the lost earnings disincentive removed, making demand and supply resources more alike from the utility's perspective.

C. Sales-per-customer adjustment

Sales-per-customer decoupling is identical to total sales recovery with the exception that the basis is sales per customer rather than total sales. If the number of customers is unchanged from the baseline number of customers usually set in the last rate case, these two methods are equivalent. Growth of the customer population enhances a utility's earnings under the sales-per-customer methodology. Customer growth-related sales growth under the total earnings methodology is an offset against sales losses.

To calculate the charge, take the expected sales per customer and compare it to the average actual usage. Then multiply that difference by the actual number of customers times the lost fixed cost per unit to produce the decoupling adjustment. Then divide this total decoupling adjustment by the total sales expected to create a decoupling charge.

Advocates of the sales-per-customer approach 1) believe that customer growth should not be included in a decoupling adjustment, but rather used as an offset against regulatory lag and to increase the time between rate cases; or 2) believe that the proper metric for assessing energy efficiency is use per customer and not total energy usage.

As with the total sales approach, the regulator must still establish sales baselines and the fixed costs recovered through volumetric charges. The sales-per-customer approach eliminates the earnings loss disincentive for demand-side resources to the degree that the underlying factors have been set and calculated accurately. Audits, reconciliation adjustments, and probably hearings would be required.

D. Straight-fixed variable rate design[8]

1. Straight-fixed variable without a revenue-neutral energy efficiency adjustment

Straight-fixed variable (SFV) rate design assigns all fixed charges to fixed fees and variable costs to volumetric charges. Rate designers contrast straight-fixed variable design with traditional two-part rates. The terminology can be confusing because both forms involve two-part rates; the difference between them has to do with how each approach treats fixed costs.

[8] The author has recently written a report on the possible use of the straight-fixed variable (SFV) rate design as a decoupling tool and introduced the concept of a revenue neutral energy efficiency feebate to address the traditional concerns about the SFV rate design. Neither this recent paper (available at http://nrri.org/pubs/electricity/rate_des_energy_eff_SVF_REEF_jul08--08.pdf) nor a presentation made on the REEF to the Public Utilities Commission of Ohio (available it the Ohio Commission's website) advocate for the use of SFV rate design or the REEF as the preferred decoupling methodology.

Straight fixed variable rate design places all of a utility's fixed costs into a fixed component of a utility customer's bill, thereby recovering only variable costs, such as fuel and purchased power, on a volumetric (e.g., per-kWh or kW) basis. A standard two-part tariff, in contrast, usually collects some fixed costs through a variable charge. The SFV approach to decoupling is most unlike the other three methods as it eliminates the dependence between sales and earnings rather than rely on adjustments to eliminate the dependence. The regulator, as is the case with the other decoupling methods, must accurately identify fixed and variable costs if the decoupling is to be accurate. Some states have adopted SFV rate design for gas utilities, but the author is unaware of any application in the United States for electric utilities.

The SFV approach does not present the accuracy challenges discussed in section III.A below, as the SFV requires no adjustment between baseline and actual sales. The SFV is also less complex to administer, as it requires no adjustments, billing changes, or audits with associated hearings and reconciliation adjustments.

Critics of the SFV rate design express concerns including the following:

1. Lowering the variable component of a standard two-part tariff by moving fixed costs to the fixed charge reduces a customer's economic incentive to conserve.

2. Moving revenue from the variable component of a standard two-part tariff to the fixed charge adversely affects small users within a class, including possibly low-income customers.

One way to overcome these criticisms is to use a revenue-neutral energy efficiency feebate (REEF), discussed next.

2. Straight-fixed variable with a revenue-neutral energy efficiency adjustment (REEF)

A revenue-neutral feebate added to a SFV rate design would charge fees to customers who use more than a typical amount of electricity, while giving rebates in the same total amount to other customers in the class who use less than that amount. The utility's finances are unaffected by the REEF (i.e., revenue- and earnings-neutral), but consumers could see their bills go either up or down depending on their usage relative to other customers in their class. The REEF mechanism continuously adjusts the usage benchmarks used to determine rebates and fees accounting for changes in the consumption of different customer classes, whether associated with the weather or with a reaction to the REEF.

A REEF enhancement to an SFV rate design allows regulators to base rates on long-run marginal costs or other non-embedded cost metrics without affecting a utility's total revenues that were set based upon a utility's embedded costs[9]. The example at Table 7 shows how a $0.05

[9] Embedded-cost ratemaking looks at the utility's total actual costs and plant in service rather than at the utility's marginal costs. Marginal costs consider avoided costs, the costs of new generation, and the cost of pending environmental investments. Utility revenues under traditional embedded-cost ratemaking are set to allow a utility an opportunity to recover these

fee and rebate affects different customer's bills compared to a total sales adjustment. In all cases the utility's revenues and earnings remain unchanged, even as individual customers' bills change. If a regulator adds a fee based upon avoided costs or long-term marginal costs that are in excess of the utility's embedded cost-based revenue requirement, then the fee creates excess revenues. A post-revenue-requirement adjustment to rate design that is revenue-neutral allows the regulator to sharpen the price signals without changing the underlying total revenues earned by the utility. A regulator can design fees and rebates designed to induce certain behaviors.

Table 7 shows how the SFV works with and without a REEF and compares it to a standard tariff case with total sales decoupling. The SFV approach places more responsibility on the smaller customers than does the standard tariff, with or without decoupling, in both cases shown. Smaller customers pay more under an SFV rate design than a standard tariff because the standard tariff recovers some of the smaller customer's share of fixed charges through the volumetric charges of larger customers. Smaller customers pay less under the REEF-adjusted approach than under the standard approach, with larger customers charged a premium for the extra burden they put on the system. The results shown are assumption-specific but indicate the type of effect REEF can have even with an extreme case such as a $50/month SFV fixed charge compared to the standard fixed charge of $15.

embedded costs. Under traditional ratemaking, rates that charge a customer greater-than-average embedded costs must be offset by rates that charge less-than-average embedded costs so that the total revenues generated by the rate design equal the allowed revenue requirement.

Table 7: SFV with a Revenue-Neutral Energy Efficiency Feebate

5 customers, base average usage of 1000 kWh/mo decreasing to actual usage of 900 kWh

Std Tariff $15 fixed charge and $0.075/kWh ($0.04/kWh cost) plus decoupling

SFV tariff with $50 fixed charge and $0.04/kWh plus $0.05 feebate

Case 1: 1000kWh	**650 kWh**	**900 kWh**	**1000 kWh**	**1200 kWh**	**1250 kWh**
Standard Tariff	**$63.75**	**$82.50**	**$90.00**	**$105.00**	**$108.75**
SFV Tariff	$76.00	$86.00	$90.00	$98.00	$100.00
REEF	-$17.50	-$5.00	$0.00	$10.00	$12.00
SFV with REEF	**$58.50**	**$81.00**	**$90.00**	**$108.00**	**$112.50**
Case 2: 950 kWh	**600 kWh**	**750 kWh**	**900 kWh**	**1000 kWh**	**1250 kWh**
Standard Tariff	$60.00	$71.25	$82.50	$90.00	$108.75
Decoupling Adjustment	$2.33	$2.92	$3.30	$3.89	$4.86
Adjusted Standard	**$62.33**	**$74.17**	**$86.00**	**$93.89**	**$113.61**
SFV Tariff	$74.00	$80.00	$86.00	$90.00	100.00
REEF	-$15.00	-$7.50	$0.00	$5.00	$17.50
SFV plus REEF	**$59.00**	**$72.50**	**$86.00**	**$95.00**	**$117.50**

The REEF is relatively easy to administer, as the REEF rate adjustment uses actual sales data, eliminating the need for reconciliation that occurs when there is a mismatch between the calculation level of sales and the recovery period's sales level.

E. Side-by-side comparisons of decoupling mechanisms

Table 8 compares the effect on a utility's earnings of the four decoupling mechanisms discussed above. The SFV rate design column is without the REEF, as it is the SFV rate design and not the REEF that achieves the decoupling between sales and earnings. Table 8 separates sales and earnings changes associated with utility programs (2% assumed) and customer population growth from the total change in sales. The total reduction in sales is 5% but there is a greater decrease in sales per customer driven by the 1% increase in the customer population.

Table 8: Basic Methods				
	Lost Sales Tracker	**Total Sales**	**Sales per Customer**	**Straight Fixed Variable**
Base Sales	100,000 kWh	100,000 kWh	100,000 kWh	100,000 kWh
Base Revenue: $0.10/kWh	$10,000	$10,000	$10,000	$10,000
Base Income	$1,000	$1,000	$1,000	$1,000
Actual Sales	96,000 kWh (-4%)	96,000 kWh (-4%)	96,000 kWh (-4%)	96,000 kWh (-4%)
Actual Revenue	$9,600	$9,600	$9,600	$9,800
Actual Income	$800 (-20%)	$800 (-20%)	$800 (-20%)	$1,050
Decoupling Adjustment	**$100**[10]	**$200**[11]	**$250**[12]	**$0**[13]
Total Revenue including Decoupling	**$900**	**$1000**	**$1050**	**$1050**
Earnings Gain or Loss[14]	**-$100**	**$0**	**$50**	**$50**

[10] Earnings losses associated with utility programs (2% x 100,000 kWh x $0.05/kWh).

[11] All earnings losses associated with sales reduction (4% x 100,000 kWh x $0.05/kWh).

[12] Basis is average usage per customer. Utility keeps earnings from customer growth. Assume number of customers has increased from 1000 to 1010 (1%). Calculate average usage per customer for the base case (100 kWh/customer) and actual (95.049 kWh/customer). Subtract the two averages and multiply the remainder by $0.05/kWh in fixed costs and 1010 customers, yielding a decoupling adjustment of $250.

[13] No adjustment, as SFV rate design decouples earnings from sales.

[14] If no customer growth, earnings change is zero in sales-per-customer or SFV cases.

Note that the last two columns in Table 8 provide the same results—a $50 increase in utility income—demonstrating that the average sales approach and the SFV approach are the same from the utility's financial perspective. If there were no change in the number of customers, then the last three columns would all be alike. The lost earnings tracker produces fewer earnings because it does not adjust for assumed sales losses other than the losses attributed to utility programs.

The comparisons provided at Table 8a depend on design decisions such as allocation of decoupling adjustments, accuracy of fixed and variable cost, the distribution of lost sales among the classes and individual customers, and the size of the REEF.

Table 8a: Qualitative Comparison of Decoupling Mechanisms

	Decouples Sales and Earnings	Encourages Conservation	Administration
Lost Sales Tracker	Only decouples portion associated with utility-sponsored programs. Utility still has desire not to decrease sales other than those associated with its sponsored energy efficiency programs.	Encouragement limited to utility-sponsored programs. Utility might still oppose external conservation initiatives. Longer payback issue when utility made whole for lost earnings.	Requires upfront determination of sales effect of each program. Ongoing monitoring and evaluation in addition to audits, hearings, and reconciliation associated with next two approaches.
Total Sales	Most complete decoupling.	Longer payback issue when utility made whole for lost earnings. Payback effect depends on how decoupling is allocated and heterogeneity of conservation among customers.	Audits, hearings, and reconciliation similar to other adjustment clauses.
Sales-per-Customer	Does not adjust for earnings changes associated with change customer base. Same as Total Sales if no change in customer base.	Emphasis is on average use per customer, but ignoring sales gains associated with customer growth makes paybacks longer compared to Total Sales method. Addition of a single large customer skews metric.	Audits, hearings, and reconciliation similar to other adjustment clauses. Extra calculation to shift from total to sales-per-customer. Need to watch for gains or losses of large customers.
SFV with REEF	Same as Sales per Customer.	REEF allows regulator to send price signals not constricted by embedded cost recovery limitations.	SFV has no additional administration. REEF design does not need audits, hearings, and reconciliation.

The method the Commission finds most applicable will depend on many factors such as: the Commission's view on the appropriateness to compensate utilities for earnings associated with lost sales and the reason for those lost sales; how the Commission addresses behind the meter generation; the utility's rate structure; the Commission's concern about individual customer's ability to conserve; the availability of utility sponsored conservation programs; concern about the effect decoupling can have on customers' efforts to conserve; and the Commission's views on the tradeoffs between resources that reduce electricity sales and the generation of electricity through native resources. It is not necessary to apply the same or any decoupling methodology to every class of customer. Regulators may not find that the REEF easy to apply to industrial customers because of the lack of a homogenous comparison group. Some jurisdictions do not apply decoupling to large customers, based upon the position that decoupling can be disruptive to industrial customers' energy efficiency initiatives. Who pays for the lost earnings is a policy decision that needs to consider issues such as who is reaping the benefits of the savings associated with reduced sales and who is paying for any associated investments.

III. Decoupling: Implementation decisions

There are decisions a regulator must make in addition to what basic approach to select when implementing a decoupling mechanism. The regulator must make most of these decisions regardless of the general type of decoupling mechanism chosen.

A. How accurately must the decoupling mechanism calculate lost revenues?

The accuracy of decoupling is the difference between actual lost earnings and the lost earnings calculated by the decoupling mechanism. Lost earnings equal the product of lost sales and the fixed costs per unit that would have been recovered through those sales. The fixed cost portion of lost sales varies between customer classes and between rate components (e.g., a demand charge or an energy charge, or on peak versus off-peak charge). Because of these differences, the more finely the regulator disaggregates baseline sales and fixed costs recovered through the each rate component, the more accurate the lost earnings calculation.

1. Determining fixed costs

For decoupling to be accurate, the regulator must accurately designate costs as fixed or variable regardless of the decoupling mechanism used. The rate case provides regulators an opportunity to classify costs as fixed or variable. The most direct approach for determining the fixed costs recovered through any rate component in a utility's tariff is to net out the variable costs. The remainder is the fixed costs. A reasonable starting point for determining variable costs is fuel and energy purchases. Some purchased power costs may not be variable, such as take-or-pay provisions that do not vary with usage. Non-fuel costs such as uncollectible expenses (more uncollectible revenues when usage and bills are high), and even some depreciation or maintenance, may vary with sales (e.g., less wear and tear on a turbine when production is down).

Regulators can also determine the fixed cost recovery associated with changes in sales by rate class. This requires that the regulator designate the fixed costs allocated to the class, probably as part of a rate case. Average fixed costs recovered per kWh can be calculated and used as part of decoupling adjustment calculation. This approach is less accurate than the component approach discussed above, but more accurate than suing a single fixed cost recovery factor for all sales (see discussion on approximating lost earnings at III.A.3 below).

2. Setting baseline sales

For the best accuracy in calculating lost earnings, the regulator needs to set sales baselines for each class and rate component. These baseline sales are usually set in base rate cases, as they are necessary to determine that the final tariffs generate the allowed revenue requirement. A sales change in the residential class may have a different earnings effect than a sales change in the commercial class depending on the extent to which fixed costs are being recovered through the volumetric charge. The earnings effect of losses from on-peak versus off-peak sales changes may be very different. A one-for-one shift in sales from peak to off-peak sales in a time-of-day rate may cause a change in a utility's earnings, even though total kWh sales remain unchanged. The regulator must establish monthly, not just annual, baselines if decoupling adjustments are calculated monthly.

3. Approximating lost earnings

Regulators commonly use approximations of lost earnings in the decoupling process for simplicity. The regulator can compare baseline sales to actual sales and assign an average lost earnings to all sales lost. This provides an approximation of lost earnings. Another approximation technique is to compare allowed revenues net of energy costs to actual revenues and use that as an approximation. The first approximation differs from the actual earnings lost because earnings losses differ based upon the fixed charges recovered through different rate components of lost sales. The second approximation occurs because energy costs are not a perfect proxy for variable costs. Of the two, the second is probably a more reliable approximation, noting that class and rate component disaggregation are not identified and cannot be used in allocating the decoupling charge (see III.D, below).

B. Income taxes and decoupling

This document has not mentioned income taxes, even though the basis of decoupling is adjusting earnings (or income). The adjustment does not create new earnings from a ratemaking perspective, just the maintenance of previously authorized earnings. Taxes commensurate with these earnings have already been included in the utility's base rates. No further adjustment is necessary.

C. Frequency of decoupling adjustment calculation

A regulator can design a decoupling tariff rider that adjusts rates as frequently as the regulator deems appropriate. Annual, semi-annual, quarterly, or monthly adjustments are all possible. The appropriate frequency for adjusting the decoupling rider depends on factors such as the anticipated size of the adjustment, seasonal shifts in consumption, the effect on price signals, the importance of the decoupling adjustment to the utility's cash flow, administrative simplicity, and customer acceptance of rate changes.

A monthly adjustment requires more administrative and customer education efforts than does an annual adjustment. The monthly adjustment tracks revenues and costs more closely and provides more current price signals. Either method will require some type of reconciliation process, probably annually. The SFV rate design does not require periodic adjustments to achieve decoupling but the REEF needs frequent adjustments.

D. Allocating the decoupling earnings adjustment

The regulator first determines the amount of the lost earnings adjustment. Next the regulator must decide who should pay how much of the adjustment. Deciding on the allocation of the change in earnings (i.e., the decoupling adjustment) is important to the decoupling program design. These allocation decisions by the regulator affect price signals to customers and, therefore, promote different customer behavior. One issue is whether to allocate the lost earnings to all classes or just to the classes whence they came (see section III.D.1 below). Another issue is whether to allocate the earnings adjustment based upon energy, capacity, or some other method such as on peak kWh only (see section III.D.2, below). The regulator must address both of these aforementioned issues. The SFV approach has no allocation decision to make, although the REEF, if used, is an extra rate design decision for regulators.

1. Interclass allocation of adjusted earnings

A regulator must decide whether to allocate the decoupling earnings adjustment to all customers or allocate the changes in sales and earnings only within the class in which they occurred. Table 9 demonstrates how these different allocation mechanisms can affect different classes. In this example, there is a difference not only in the change in sales among the classes, but also in the per-kWh earnings lost per class.

Table 9: Allocating Lost Earnings to All or by Class				
	Residential	**Commercial**	**Industrial**	**Total**
Base Sales	500 kWh	200 kWh	300 kWh	1000 kWh
Actual Sales	470 kWh	200 kWh	280 kW	950 kWh
Tail Block Rate/kWh	$0.12	$0.10	$0.07	
Avoided Variable Costs/kWh	$0.04	$0.04	$0.04	
Lost Margin/kWh	$0.08	$0.06	$0.03	
Lost Earnings (Lost margin x Lost Sales)	$2.40	$0	$0.60	$3.00
Decoupling Adjustment Allocated across the Board ($3.20/950kWh=$0.00318/kWh)	**$1.48**	**$0.63**	**$0.89**	**$3.00**
Decoupling Allocated by Class **(Class Loss Earnings/Class Sales)**	**$0.0051/kWh** **$2.40**	**$0.00/kWh** **$0.00**	**$0.0029/kWh** **$0.60**	 **$3.00**

Table 9 shows how different customer classes are affected, depending upon whether the regulator allocates the decoupling adjustment to all, or only within the class in which the sales change occurred. When the regulator keeps the total decoupling adjustment of $3.00 within each class, no adjustment is allocated to commercial customers who did not conserve. When there is across-the-board allocation of the decoupling adjustment, commercial customers are billed $0.63 of the $3.00, in proportion to the class' total kWh consumption. The residential class adjustment decreases from $0.0051/kWh and $0.00318/kWh when the adjustment shifts from by-class to across-the-board. The industrial adjustment is higher under the across-the-board allocation in the example because it is now bearing a portion of the relatively higher residential earnings loss of $2.40.

In making this allocation decision, the regulator should consider whether all customers benefit from energy efficiency or just the customers that improve their own energy efficiency.

Regulators should also consider the cost allocations of the utility-sponsored energy efficiency programs and whether all classes have access to utility-sponsored programs.

2. Allocating earnings adjustments by rate component or kWh

A regulator can allocate the decoupling mechanism's calculated change in earnings by kWh or allocate these earnings to individual rate components. The discussion here builds on the discussion about interclass allocation. Table 10b provides three examples of allocating lost earnings by rate components (see Table 10a for the underlying assumptions). Case 1 allocates the earnings adjustment based upon kWh—the same approach used in Table 9 above for across-the-board allocation. Case 2 is an across-customer-class approach, with the additional wrinkle of allocating lost earnings based upon individual rate components (e.g., residential customers with no billing demand are assigned no responsibility for the earnings losses associated with billed demand). Case 3 keeps adjustments within each customer class and has the same total interclass effect as in Table 9, while further allocating the lost earnings by rate component within each class.

Table 10a: Allocation By Rate Component – Assumptions				
	Residential	**Commercial**	**Industrial**	**Total**
On-peak kWh – base	300 kWh	125 kWh	150 kWh	575 kWh
Off-peak kWh – base	200 kWh	75 kWh	150 kWh	425 kWh
Billed demand – base	NA	2 kW	2 kW	4 kW
On-peak kWh - actual	280 kWh	125 kWh	140 kWh	545 kWh
Off-peak kWh – actual	190 kWh	75 kWh	140 kWh	405 kWh
Billed demand – actual	NA	2 kW	1.75 kW	3.75 kW
On-peak tail block	$0.155	$0.12	$0.08	
Off-peak tail block	$0.08	$.045	$0.04	
Demand Charge	NA	$2.00	$1.80	
On-peak avoided cost	$0.06	$0.06	$0.06	
Off-peak avoided cost	$0.03	$0.03	$0.03	
Avoided demand	$0	$0	$0	
On-peak lost earnings	$1.90	$0	$0.20	$2.10
Off-peak lost earnings	$0.50	$0	$0.10	$0.60
Demand lost earnings	NA	$0	$0.30	$0.30
Total lost earnings	$2.40	$0	$0.60	$3.00

Table 10b: Allocation By Rate Component – Three Examples				
	Residential	**Commercial**	**Industrial**	**Total**
Case 1: Decoupling allocated based upon kWh ($3.00/950 kWh)	**$1.48**	**$0.63**	**$0.89**	**$3.00**
Case 2: Decoupling allocated based upon rate components across rate classes				
On-peak ($2.10/545kWh)	**$1.08**	**$0.48**	**$0.54**	**$2.10**
Off-peak ($0.60/405 kWh)	**$0.28**	**$0.11**	**$0.21**	**$0.60**
Demand ($0.30/3.75 kW)	**$0.00**	**$0.16**	**$0.14**	**$0.30**
Total	**$1.36**	**$0.75**	**$0.89**	**$3.00**
Case 3: Decoupling allocated based upon rate components within rate classes				
On-peak	**$1.90**	**$0**	**$0.20**	**$2.10**
Off-peak	**$0.50**	**$0**	**$0.10**	**$0.60**
Demand	**NA**	**$0**	**$0.30**	**$0.30**
Total	**$2.40**	**$0**	**$0.60**	**$3.00**

The three cases demonstrate the type of effect the regulator's allocation decision can have on individual customers and customer classes. Case 2 assigns only $1.36 in lost earnings back to residential customers, the lowest amount of the three cases. This outcome occurs for two reasons. The across-all-class rate-component approach assigns the residential class none of the $0.30 earnings losses associated with billing demand because residential customers have no billing demand. The second reason is that although residential customers caused $1.90 of the $2.10 in on-peak earnings losses (90%), the residential share is only 52% (300 kWh/575 kWh) as the allocation method allocates responsibility for lost earning by usage.

The table also indirectly shows that when the responsibility for lost earnings is allocated by rate component, whether within or across customer classes, that individual customers will be affected differently depending upon their consumption behavior (e.g., demand and energy usage). The regulator needs to assess how an allocation strategy affects different customer groups and the program's overall goals. The regulator could implement many other potential allocation approaches, and the Commission should ask the parties to discuss the allocation question fully.

E. Partial decoupling

An implementation option for decoupling is rather than adjusting for the full amount of lost income the Commission may choose a percentage share, (e.g., 75%). Partial decoupling shares the risk of sales variation between the utility and its customers. The lost revenue tracker is a partial decoupling method, as it does not recognize all sales changes and the sales- per customer is also a partial decoupling technique as it excludes changes in sales based upon number of customers.

A partial decoupling approach on a percentage basis reduces the conservation disincentive associated with decoupling (customers who invest to conserve have longer paybacks) but reduces the conservation incentive to those who do not conserve by reducing the average cost per kWh. A partial decoupling method also has less effect on the utility's financial risk than a full decoupling method and should, therefore, decrease any change to the utility's financing costs (e.g., capital structure and return on equity – see III.F below). There is no mechanical reason that prohibits the Commission from making a partial adjustment.

The Commission should ask the parties to provide reasons for deviating from 100% adjustments. If there is a deviation from 100% recovery, should the deviation be symmetric? For example if sales decrease, does the utility receive 75% of the calculated lost earnings but when sales increase, customers get 100% of the adjustment? How does a partial adjustment help meet the goals of the Clean Energy Initiative?

F. Risk allocation between customers and investors

Decoupling reduces and can even eliminate a utility's financial risk associated with variations in sales. Weather, economic cycles, energy efficiency, price elasticity, changes in technology, and non-utility owned distributed generation all affect a utility's sales. Decoupling mitigates the financial risks associated with all of these variations in sales, helping to ensure that a utility has the revenues needed to produce earnings. Regulators need to consider what adjustment in a utility's return, if any, is appropriate to compensate ratepayers for assuming risks associated with lost earnings from lost sales. The Commission should have the parties address the effect of decoupling on the utilities' "beta" (a measurement of risk) and what that means to the utility's return. The Commission should not just look at the reduced risk's effect on return on equity but on the utility's overall capital structure. The effect that a shift in the capital structure from common equity to debt has on a utility's revenue requirement can be more significant than the effect caused by a reduction in the return on equity. Not all decoupling methods have the same effect on risk. As shown at Table 8, the sales-per-customer approach to decoupling provides a utility with an opportunity to earn more than the total sales approach when there is growth in the number of customers. The lost sales tracking approach does not mitigate as much of the sales lost risk as the other methods.

G. Metering and customer service systems

The regulator must assess the utility's ability to implement decoupling before ordering decoupling. Decoupling does require a certain amount of information management. Some decoupling approaches (e.g., allocation by tariff component) require more calculation than an across-the-board adjustment.

Another customer service information question is how the regulator should order the utility to post the decoupling charge on customers' bills. Is the charge posted without any explanation? Does the utility need to include enough information so that the customer can understand how the charge was calculated? Do customers' bills need to state a decoupling adjustment for each rate component affected?

Finally, can the decoupling mechanism selected by the regulator be based upon estimated meter readings? Estimated meter readings create additional uncertainty and offer less transparency as the adjustment depends on the difference between baseline and actual sales. Does the utility need to implement some type of automatic meter reading program as part of a decoupling plan to reduce estimated billings?

H. Customer education

Before implementing any of these decoupling regimes, the utility and regulator need to explain the change in rate design to customers. For the customer to accept decoupling, the regulator should ensure that the customer understands several items about decoupling, such as:

- The role of decoupling in having utilities consider supply and demand resources equivalently if customers are to get the most cost-effective long-term mix of resources;
- Adjustments the regulator has made to rate of return associated with decoupling that have reduced the customer's base rates;
- How decoupling defers rate cases, as earnings attrition associated with improved energy efficiency is eliminated;
- The effect on the customer's total bill versus the effect on rates; and
- How to read the decoupling adjustment posted on the customer's bill.

IV. Suggested next steps

The author recommends that the Commission direct the parties to its decoupling investigation, consistent with the Commission's timeline, to:

1. Provide comments to this paper.

2. Answer the questions listed in the Appendix of this report in detail, providing supporting citations and calculations.

Appendix 1: Section 28 of the Energy Agreement, October 2008

The transition to Hawaii's clean energy future can be facilitated by modifying utility ratemaking with a decoupling mechanism that fits the unique characteristics of Hawaii's service territory and cost structure, and removes the barriers for the utilities to pursue aggressive demand-response and load management programs, and customer-owned or third-party-owned renewable energy systems, and gives the utilities an opportunity to achieve fair rates of return. The parties agree in principle that it is appropriate to adopt a decoupling mechanism that closely tracks the mechanisms in place for several California electric utilities, as follows:

1. The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Company Rate Case (most likely in the summer of 2009).

The utility will use a revenue adjustment mechanism based on cost tracking indices such as those used by the California regulators for their larger utilities or its equivalent and not based on customer count. Such a decoupling mechanism would, on an ongoing basis, provide revenue adjustments for the differences between the amount determined in the last rate case and:

(a) The current cost of operating the utility that is deemed reasonable and approved by the PUC;

(b) Return on and return of ongoing capital investment (excluding those projects included in the Clean Energy Infrastructure Surcharge); and

(c) Any changes in State or federal tax rates.

Adjustments shall occur on a quarterly basis, semi-annual, or annual based or the availability of the indices utilized. The adjustments will continue until such time that they are incorporated in the utility's base rates.

2. The parties agree that the decoupling mechanism that will be implemented will be subject to review and approval by the PUC.

3. The utility will continue to use tracking mechanisms for Commission-approved pension and other post-retirement benefits to ensure that the expenses are evened out for the ratepayer and are not subject to sudden and dramatic swing.

4. The Commission may review the decoupling mechanism at any time if it determines that the mechanism is not operating in the interests of the ratepayers.

5. The utility or the Consumer Advocate may also file a request to review the impact of the decoupling mechanism.

6. The Commission may unilaterally discontinue the decoupling mechanism if it finds that the public interest requires such action.

7. In order to implement the decoupling mechanism, the parties agree that HELCO and MECO will file for a 2009 test year rate case.

Appendix 2: Questions for the Parties

1. Why do electric utilities need decoupling at this time? Please address decoupling needs created by the utility's rate design and Hawaii's emphasis on electricity strategies that would reduce utility sales. If possible, quantify the need.

    1.1. Does the administration of the energy efficiency programs by a third-party administrator affect the need for and potential benefits of decoupling?

    1.2. Is the need for decoupling the same on each island? Please consider the frequency in curtailments of as-available renewable generation.

2. Please propose a preferred decoupling methodology and in doing so, please answer these questions.

    2.1. Should the decoupling process decouple the utility's earnings (or revenues) from the effects of changes in weather, economic upturns/downturns, taxes, costs of financing, the utility's credit rating or other external variables? How are the sales impacts of efficiency programs segregated from these factors, and how does the commission monitor these factors going forward?

    2.2. Does decoupling that ensures a utility's earnings associated with lost sales create a disincentive for utilities to manage these costs effectively or to invest in capital projects rather than purchase energy or other services?

    2.3. Does it eliminate the utility's bias against reduced sales?

    2.4. Does it accurately decouple sales and earnings (i.e., reinstate authorized earnings associated with lost sales)? Please provide supporting examples and calculations that address how lost earnings are calculated.

    2.5. Does it encourage customers to be energy efficient?

    2.6. Is it easy to understand?

    2.7. Are Hawaii's electric utilities' existing metering and customer service systems adequate to support decoupling? If no, recommend enhancements.

    2.8. Is it easy to administer (monitoring, audits, hearings, reconciliation)? Estimate the administrative costs including regulatory costs.

    2.9. If the proposed method herein is different from the method proposed by the Agreement, why is it superior?

3. What actions, if any, are required to identify with accuracy each utility's fixed and variable costs?

3.1. What fixed charges are recovered through the utility's volumetric rates by rate component?

3.2. Is the information needed to allocate costs into fixed and variable costs included in a current rate filing? If yes, please provide.

3.3. How should the Commission differentiate between fixed and variable costs?

3.3.1. What timeframe should the Commission consider in setting fixed and variable costs?

3.3.2. Are some "fixed costs" simply long-run variable costs that appear fixed in the short term and how should this affect decoupling?

3.4. To what extent, if any, should the Energy Cost Adjustment Clause (ECAC) be modified if decoupling is enacted? Are any fixed costs recovered via the ECAC, and if so, should they be removed? To what extent should performance incentives inherent in the clause be modified or removed in order to remove the connection between utility sales and earnings? Should these incentives instead be recovered through the other charges?

4. What level of specificity is required on a customer's bill to support a decoupling adjustment (e.g., if allocated by rate component, should there be a line item for each part of the decoupling adjustment on the bill)?

5. Do all customers share in the benefits of improved energy efficiency, or only those customers who improve their own energy efficiency?

5.1. What does the allocation of benefits indicate about the allocation of decoupling's earnings adjustments?

5.2. How should the Commission consider each utility's capacity and energy availability in determining the allocation of the decoupling adjustment?

5.3. Please propose and discuss an allocation methodology for the decoupling methodology proposed at question 2, above. Include responses to the following questions.

5.3.1. How much of the anticipated change in sales is driven by utility-sponsored programs? Are the programs available to all classes of customers? How are these costs allocated?

5.3.2. Can the utilities' net metering protocols allow behind-the-meter renewable energy to be tracked as a distinct cause of lost sales?

5.3.3. Does customer growth or attrition mask or exaggerate actual energy efficiency trends?

5.3.4. Aside from utility-sponsored programs, do all classes of customers have the same cost-effective opportunities for energy efficiency improvements?

5.3.5. Can and should the decoupling charge be allocated to promote specific energy efficiency goals such as cutting peak demand or reducing carbon emissions?

5.3.6. Does energy efficiency offer greater benefits to the economy in one sector than in another?

5.3.7. The utilities contend that some rate classes produce higher rates of return than others do. To the extent that these differences exist, how should they be addressed under the proposed decoupling process?

6. Should the Commission allow the full recovery of lost earnings though the decoupling adjustment or only some percentage of the calculated lost earnings? How much of the risk associated with a change in sales should remain with the utility?

6.1. If there is a deviation from 100% recovery, should the deviation be symmetric? For example if sales decrease, does the utility receive 75% of the calculated lost earnings but when sales increase, customers get 100% of the adjustment?

6.2. How does a partial adjustment help meet the goals of the Clean Energy Initiative?

7. How much, if any, of a rate-of-return adjustment is commensurate with the greater certainty in earnings provided by decoupling?

7.1. To the extent that decoupling results in less financial risk for the utility, how should the commission quantify that effect and how should this be flowed through to the utility's rate of return?

7.2. Please quantify decoupling's effect on the utilities' "beta" (a measurement of risk) and what that means to the utility's return and ability to move to a capital structure with more debt.

7.3. Can input from the rating agencies be included during development of the decoupling process?

8. Some customers may not have the same opportunity to conserve electricity as other customers because differences such as income, access to capital, age, and renting versus owning. How should decoupling adjustments be structured to address this lesser ability to conserve?

9. Please propose a customer education program for the decoupling mechanism proposed at question 2 and the allocation methodology proposed at 5.2.

10. To the extent that the decoupling mechanism is intended to help reduce energy consumption, can this adversely affect the state's efforts to incorporate more as-available

renewable energy into the grid? Can reduced consumption cause more instances where as-available energy must be curtailed due to the utility's system constraints?

11. Do the rate changes associated with the decoupling mechanism merit a new rate case for HECO pursuant to Hawaii Revised Statutes, Chapter 269, or can the changes be accomplished within the scope of the existing HECO rate case? Are public hearings needed, considering the extent of the expected rate changes?

12. Various provisions of the HCEI propose utility surcharges, where the utility will fairly immediately recover its costs (potentially both fixed and variable) through a surcharge that is separate from the normal rates. How can the commission effectively decouple this aspect of the utility rates? Do these surcharges impact the effectiveness of the efforts to decouple rates from earning?

    12.1 Please provide details of changes that need to be made to the various HCEI proposals that have already been filed as a result of decoupling.